STATE OF CALIFORNIA
ELECTRICITY OVERSIGHT BOARD

Gray Davis, Governor

April 9, 2002

Ms. Magalie Roman Salas, Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

VIA EMAIL

Re: Electricity Market Design and Structure (RTP Cost Benefit Analysis Report), Docket Nos. RM01-12-000 et al.

Dear Ms. Salas:

Please file the attached electronic version of the Comments of the California Electricity Oversight Board on the RTO Cost Benefit Analysis Report.

Thank you for your assistance.

Sincerely,

Sidney Mannheim Jubien

Sidney Mannheim Jubien
Senior Staff Counsel
Electricity Oversight Board

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Electricity Market Design and Structure (RTO Cost Benefit Analysis Report)	Docket Nos. RM01-12-000 *et al.*

COMMENTS OF THE CALIFORNIA ELECTRICITY OVERSIGHT BOARD

The California Electricity Oversight Board (CEOB) offers the following comments on the February 27, 2002, ***Economic Assessment of RTO Policy*** (Report) prepared by ICF Consulting on behalf of the Commission. The Report analyzes potential benefits and costs of moving toward formation of Regional Transmission Organizations (RTOs) and implementation of the Commission's RTO policies.[1]

The CEOB was created as a component of California's comprehensive restructuring legislation. The CEOB's statutory responsibilities include oversight of the California Independent System Operator Corporation (CAISO), the energy and ancillary services markets administered by the CAISO, and the reliability of the California electric grid.

The principal office of the CEOB is located at 770 L Street, Suite 1250, Sacramento, California, 95814. All pleadings, orders, correspondence and communications regarding this motion should be directed to the following persons:

[1] As part of the analysis, ICF also developed wholesale price forecasts for the different regions. These comments do not discuss these forecasts, but rather focus on the benefit-cost results and the assumptions, implicit and explicit, that drive those results.

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I. SUMMARY OF REPORT

A. Summary of Scenarios

ICF developed six scenarios for its study:

- Base Case – representation of power flows and use in the year 2000 with forecasts through 2021; Thirty-two regions in continental U.S. represent existing control areas;[2] Transmission hurdle rates were used to constrain power flows between regions.
- Transmission Only Case – Consolidation of 32 regions into 4 RTOs and ERCOT; Transmission constraints relaxed by reducing transmission hurdle rates; assumption of capacity sharing and reduction of reserve margins; Initial startup costs of RTO were captured, but ongoing expenses were not.
- RTO Policy Case (with decreasing numbers of RTOs nationwide) – Transmission Only Case with increased generator performance.

[2] For some reason, ICF divides the CAISO control area into two regions: Northern California and Southern California and Southern Nevada.

- 2 RTOs and ERCOT
- 4 RTOs and ERCOT
- 9 RTOs and ERCOT

- Demand Response Case – RTO Policy Case with 3.5 percent reduction in peak load.[3]

ICF found that the Transmission Only Case would result in reduced production costs of about $6 billion in present value over the 20 years of the study (2002 – 2021). (See Table 1.) The RTO Policy Case reported approximately $41 billion in present value savings ($34 billion more than the Transmission Only Case). ICF estimated that the Demand Response Case would result in about $60 billion in present value savings ($54 billion more than the Transmission Only Case and $19 billion more than the RTO Policy Case).

Table 1
Detailed Comparison of Scenarios

Source of Benefit	Transmission Only Case	RTO Policy Case (4 RTOs)	Demand Response Case
Reduction in intra-RTO transmission hurdle rates to $0/MWh by 2004	X	X	X
Reduction in inter-RTO transmission hurdle rates to $2/MWh by 2004	X	X	X
Intra-RTO transfer capability increased by 5%	X	X	X
Capacity sharing equal to total import capability to meet reserve margins	X	X	X
Lower reserve margins (from 15% to 13%)	X	X	X
Lower forced generation outages by 2.5%		X	X
1% annual reduction in heat rates from 2004 to 2010		X	X
Peak demand reductions of 3.5%			X
Total PV Savings in billions (2002-2021)	$6.2	$40.9	$60.0

[3] The 3.5 percent peak load reduction is in addition to any currently ongoing peak load reduction, which ICF estimates at about 4 percent.

ICF also analyzed the cases of 2 and 9 RTOs. (See Table 2.) The case of 2 RTOs had a present value savings of slightly more than $40 billion, while the case with 9 RTOs had a present value savings of $41 billion.

Table 2
Comparison of RTO scenarios

	9 RTOs	4 RTO	2 RTOs
Projected PV Savings in billlions	**$40.2**	**$40.9**	**$41.4**
Projected Incremental PV Savings in billions		**$ 0.7**	**$ 0.5**

Based primarily on FERC Order 2000, ICF assumes the following benefits will be realized from appropriately designed RTOs:

1. Improved efficiencies in transmission grid management;
2. Improved grid reliability;
3. Fewer discriminatory transmission practices;
4. Improved market performance enhanced by competition; and,
5. Facilitation of light-handed government regulation.

B. Summary of Analytical Approach

ICF used its proprietary Integrated Planning Model (IPM) to quantify the benefits of RTOs. The IPM is an integrated wholesale energy, air pollution, fuel and capacity additions model. ICF modeled 32 regions in the contiguous U.S. in IPM. IPM added generation capacity as needed and retired older generation capacity as it became uneconomic.

The Base Case was developed as a simulation of power flows and energy use in the year 2000. Transmission "hurdle rates" were used to constrain inter-regional flows in order to get within 5 percent of actual flows. The hurdle rates are used to raise (or lower) transmission prices to lower (or raise) transmission flows on various paths. ICF iteratively changed the hurdle rates to calibrate model results with actual flows. ICF states that the hurdle rates represent actual transmission usage fees and market inefficiencies (market power, open access limitations, non-economic contracts and other barriers that impede economic power flows).

A 15 percent reserve margin was used in most regions, with the exception of the Northeast and Florida. In these regions, reserve margins started out higher, but were reduced to 15 percent by 2020.

In the Transmission Only Case, the following assumptions were made:

1. A reduction in intra-regional (within a RTO) transmission hurdle rates to \$0 per MWh by 2004. This is equivalent to having no congestion and no existing contract rights on internal paths within the RTO;
2. A reduction in inter-regional (between RTOs) transmission hurdle rates to \$2 per MWh by 2004. This has the effect of increasing flows between the RTOs;
3. An increase in intra-regional transfer capability of 5 percent to represent "better incentives for transmission investment and improved regional planning;"
4. Capacity sharing assumed to be equal to total transfer capability between RTOs.[4] This allows an RTO to use the full capacity of inter-regional transmission to offset internal reserve requirements; and

[4] In the Base Case, capacity sharing was restricted to 75 percent of total transfer capability.

5. A two percent reduction in (planning) reserve margin to an average of 13 percent from 15 percent by 2020. This is to reflect the benefit of pooling in larger systems.

In the RTO Policy Case, all the above assumptions were retained and the following added to reflect increased incentives for generators in competitive markets:

6. Forced outages decrease by 2.5 percent between 2004 and 2010; and.
7. Reduction in heat rates by 1 percent per year from 2004 to 2010.

In the Demand Response Case, all of the above assumptions were retained and the following added to reflect demand elasticity in response to higher peak prices:

8. Peak load reduction of 3.5 percent starting in 2004.

II. COMMENTS

The CEOB believes that the Report is seriously flawed. The first and most critical flaw is that the Report does not analyze what the actual effects of RTO creation across the continental U.S. Rather, the Report assumes the following benefits—taken from the Commission's Order 2000—will exist if RTOs are created:

1. Increased trade among the former local areas within the new RTOs;
2. Increased trade among RTOs;
3. Increased use of imports to offset reserve requirements, and;
4. Generator efficiency improvements.

The Report then purports to quantify the benefits. Yet, ICF does not provide a justification for these inferred benefits or for many of the assumed values.

The largest sources of cost savings arise from improvements in generator efficiency ($34.7 billion) and peak load reduction ($19.1 billion). Cost savings in these areas are not necessarily related to RTO formation and, in fact, can be achieved without RTO development. Reduction in outages can be accomplished through better maintenance procedures and coordination within the current areas. Reductions in heat rates can be accomplished through regulatory incentives for IOUs and existing incentives of merchant generators to increase their profitability. ICF also inaccurately assumes no cost to increased generator performance.

Peak load reductions can only be accomplished when consumers consume less during peak hours. Accordingly, the primary means for achieving peak load reduction is through retail rate design, which is subject to each state's regulatory authority. The Report also appears to assume simple peak load reductions. The CEOB believes load will more likely shift from peak to other hours of the day. As a result, total energy will decline less than the peak load and thereby lower the assumed cost savings. ICF also appears to assume no cost to this peak load reduction. Many demand reduction programs are not based on consumers deciding to consume less in response to a price signal. Instead, demand programs offer compensation to those willing and able to reduce demand in the form of lower electricity rates or per MWh payments for demand reductions.

The CEOB believes that the only benefits that can appropriately be attributed to RTO formation are those under the Transmission Only Case. These benefits are based on the assumed ability for end-use customers in high cost areas to have access to lower cost energy and the ability of energy suppliers in lower cost areas to sell power to customers in higher cost areas. As found in cost benefit studies referred to in the Report, customers in higher cost areas could end up paying less but customers in low cost areas would pay more. For example, in its study of the northeast, assuming what is now PJM, the New York ISO and the New England ISO were merged into a single RTO, LECG found that customers in New York city would enjoy lower electricity prices while customers everywhere else would pay higher prices. Report at 20. Moreover, this result assumes that these cost savings would actually be achieved and that the cost savings would be passed on to end-users. As those of us in California and the Pacific Northwest well know, cost savings cannot be assured and profit-maximizing sellers will endeavor to retain the cost savings to increase their profitability.

The Report's use of "hurdle rates" appears to be the mechanism for capturing cost savings associated with economic transactions that could have, but failed to occur in the 2000 Base Case for whatever reason, including the exercise of market power, pancaking of transmission rates etc. With respect to "hurdle rates," the Report makes three questionable assumptions: (1) that hurdle rates within existing regions, such as the CAISO and PJM, are $0 per MWh; (2) that hurdle rates within newly formed RTOs will be reduced to $0 by 2004; and (3) that the regional hurdle rates between RTOs will be reduced to $2 per MWh beginning in 2004. Assuming the intra-regional hurdle rate to be $0 is equivalent to assuming that there are no inefficiencies within existing regions, such as the CAISO or PJM, for example. To be analytically consistent, if one were to assume that RTO formation would reduce hurdle rates, one would equally have to assume that ISO formation would reduce hurdle rates within the region joined in the ISO. Thus, since the Report assumes that reduction of hurdle rates will be a benefit of RTO formation, the Report also must necessarily assume that the same benefit has already occurred within ISO regions. As a practical matter, inefficiencies within the CAISO are well known and continue to exist. These inefficiencies include exercise of market power and existing transmission contract rights, two areas that cannot be eliminated through improved market design. The CEOB believes that inefficiencies are likely to exist within PJM despite the merits of PJM's market design. The utilities within PJM continue to own substantial generation resources and each utility can be expected to dispatch its resources (albeit in merit order) to meet native load. Thus, such utilities will not take full advantage (or less advantage than they might) of power pooling or purely competitive supply of disaggregated generation resources.

In addition, the assumed reduction of hurdle rates to $0 within RTOs and $2.00 between RTOs is purely arbitrary. Moreover, just as inefficiencies remain within ISOs despite ISO formation, inefficiencies will remain despite RTO formation.

The CEOB doubts other benefits associated with the Transmission Only Case. The Report's assumption that imports can be substituted for internal resources up to the inter-RTO transfer capability is questionable. It is possible that the loss of the import capability would be a large contingency for any RTO and would thus require that internal resources provide reserve capability.

Further, the reduction in planning reserve margin to a system average 13 percent from 15 percent is arbitrary. It is possible that reserve margins may fall, but given that each sub-region in the RTO has its own transfer limits with other sub-regions, it may not be possible to reduce the planning reserve margin by that amount.

On the cost side of the equation, the Report unrealistically assumed that there were no ongoing operating or capital costs to RTOs. The Report should include significant ongoing operating costs to RTOs, such as ongoing maintenance costs of software, programmers (contract or employee), control room operators, communications, settlement personnel, etc. There will also be significant startup and ongoing costs to market participants to either obtain new software and hardware or to modify their software and hardware to interface with RTOs. The revenue requirements of the PJM and the NY-ISO are $60-$100 million a year. The revenue requirement of the CAISO is over $200 million per year. RTO costs cannot be assumed away.

The Report also ignores the costs associated with increased use of the transmission system. The current transmission system was not built primarily to allow frequent market trades. ICF assumes that there will be better utilization of the transmission system, but no cost associated with that increased utilization. Increased use of the transmission system may require increased maintenance (at the very least increased inspections) and augmentation of transmission lines and substations.

Finally, ICF assumes all resources are pooled in the dispatch for the RTO. This would mean that local resources are not necessarily dedicated to meet local load except in cases of transmission constraints (of which there would be few given the $0 per MWh intra-RTO transmission hurdle rate). Municipal resources and resources owned by traditional investor-owned utilities would be dispatched to meet load in other regions or in other RTOs. However, forming RTOs will not, at least by itself, result in economic merit order dispatch of all generation resources either within or between RTOs. For example, use of publicly-owned or financed resources may conflict with the private use provisions of the tax-exempt bond financing used to fund construction. This potential conflict also applies to the use of tax-exempt bond financing of transmission lines.

Resources used to fulfill purchased power contracts also would not necessarily participate in economic dispatch of resources.

III. CONCLUSION

The CEOB believes that the Report provides little insight into the true likely costs and benefits of RTO formation. With the exception of the Transmission Only Case, the benefits discussed would not be dependent upon RTO formation. The benefits of the Transmission Only Case assume that the costs captured by “hurdle rates” simply disappear. The costs captured in hurdle rates are not costs incurred but for the existence of RTOs. There are many other drivers of these costs that will not be directly affected by RTO formation. In addition to overestimating the benefits of RTO formation, the Report also underestimates the costs of RTO formation. For a cost benefit analysis to be meaningful, it must objectively evaluate both benefits and costs. The CEOB recommends that the Commission issue an RFP for a true cost-benefit analysis.[5]

Dated: April 9, 2002

Respectfully submitted,

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[5] In defense of ICF, the CEOB believes that it was not asked to perform a true cost-benefit analysis, nor was it given adequate time to conduct such analysis. The Commission’s primary purpose of the Report was to value certain assumed benefits.

CERTIFICATE OF SERVICE

I hereby certify that I have caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary for this proceeding on April 9, 2002, pursuant to Rule 2010(a) of the Commission's Rules of Practice and Procedure.

Dated at Sacramento, California, this 9th day of April 2002.

/s/

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